ER 96 Staff Testimony

ELECTRICITY SUPPLY AND DEMAND BALANCE

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INTRODUCTION

A fundamental requirement of the Warren-Alquist Act is that the Commission evaluate in the biennial Electricity Report (ER) proceeding the potential environmental, economic, health and safety impacts of constructing and operating anticipated new power facilities. It was the original intent of this project to collect and analyze information provided by utilities (independent generators as well as investor- and publicly-owned franchise monopolies) to assist the ***ER 96*** Committee in developing its assessment of the impact of probable resource additions — its Integrated Assessment of Need (IAN). However, given the anticipated increased competitiveness of the restructured electricity industry, few utilities filed information about their specific future plans to acquire or construct new resources. Therefore, this testimony is necessarily limited to an evaluation of the extent to which the existing and committed supply of electricity is adequate to meet demand, a general description of the characteristics of the existing utility generation systems, and a generic discussion of the wide menu of potential future resources available to California's electricity suppliers.

This testimony addresses questions asked by the ***ER 96*** Committee in its February 15, 1996, Order Establishing the Issues to be Covered in ***ER 96*** relating to the role of government in assessing the need for power facilities. Specifically, this testimony addresses the following questions: What levels of supply and demand are likely? How do demand and supply balance for each service area, for the state as a whole, and for other categories that may be appropriate to consider in a restructured market? What is the need for government action to ensure that supplies are adequate to meet demand?

SUMMARY

Staff compared statewide capacity requirements to forecasts of capacity supplies, including existing and committed power plants and inter-utility bulk power purchases, and expected savings from uncommitted demand-side management (DSM) programs (Table 1). Staff included three different levels of uncommitted DSM in its comparisons. Each level of DSM savings assumes a different level of future DSM funding is available. Under the Declining DSM scenario, statewide capacity deficits occur by the year 2000, reaching almost 5,000 MW by the year 2003 and more than 10,000 MW by the year 2007. Under the Business As Usual DSM scenario, statewide capacity deficits are delayed beyond 2000 but reach about 2,500 MW by 2003 and 6,500 MW by 2007. Under the Restored Funding DSM scenario, statewide capacity deficits are only about 1,400 in 2003 and about 4,600 in 2007.

Table 1
Statewide Capacity Surplus/Deficit MW

Uncommitted DSM Level	2000	2003	2007	2015
Declining DSM	-412	-4756	-10354	-21438
Business As Usual	591	-2520	- 6500	-14948
Restored Funding	1132	-1367	- 4580	-12102

These statewide comparisons of loads and resources should not be interpreted to mean that significant power plant building programs must begin immediately. Our counting of the amount of supply resources available to the state's utilities is fairly conservative. Only resources currently committed to a utility are counted. For example, it does not include short-term contracts which many utilities use to supplement committed resources. The current western regional market has capacity resources available to California utilities which have not been included.

Likewise, these statewide comparisons of loads and resources should not be interpreted to mean that all California utilities have capacity surpluses through the year 2000. The statewide comparison nets out one utility's surpluses and deficits with another's Therefore, some utilities could have deficits much sooner or much later than indicated by the statewide totals. Individual utility electricity supply and demand balances are discussed below.

OVERVIEW

The first section of this testimony summarizes the **statewide** forecasts of system capacity requirements, three scenarios of uncommitted DSM forecasts, and existing and committed supply resources. The result is three forecasts of statewide capacity surpluses or deficits over the 20-year planning period.

The next section of the testimony summarizes the **service area** forecasts of system capacity requirements, existing and committed supply resources, and, where appropriate, three scenarios of uncommitted DSM forecasts. A brief description of issues facing each utility is also included in this section of the testimony.

Attachment 1 provides a detailed capacity resource accounting table for each individual utility service area for each of the three uncommitted DSM scenarios. **Attachment 2** provides less detailed snapshot year utility demand and supply balances and statewide and other subtotals.

LIKELY LEVELS OF SUPPLY AND DEMAND

Statewide Demand

The Commission adopted forecasts of future demand for electricity in California for the upcoming 5-, 12-, and 20-year periods in its March 29, 1996, order, Final Electricity Demand Forecasts for ***ER 96***, Order No. 96-0327-02. The statewide adopted peak demand and energy requirements forecasts are shown in **Table 2**.[1] The service area adopted peak demand and energy requirements forecasts are shown in **Tables 3 and 4**, respectively. These adopted forecasts represent the peak demand and energy requirements of electricity end users within the indicated franchise monopoly service territories. These forecasts both include the effects of existing and committed conservation and load management programs. California's electricity systems' requirements are greater than the amount of electricity actually consumed by end users. Additional capacity must be supplied to provide for transmission and distribution losses, interutility bulk power exports, and long-term capacity reserves needed to maintain reliability standards. The peak demand forecasts in **Table 2** include the amount of capacity required to "serve" transmission and distribution losses, but not exports or capacity reserve requirements. The energy forecasts do not include losses or exports.

Table 2
Statewide Annual Peak Demand and Energy End Use Forecasts

	2000	**2003**	**2007**	**2015**
Non-coincident Peak Demand MW (includes losses)	55,422	58346	61,901	68,032
Annual Energy Requirements MW (excludes losses)	265,435	279,528	296,514	324,727

Table 3
***ER 96* Peak Demand Forecasts**
Planning Area and Statewide
(MW)

[this is table 8 from demand forecast order]

Table 4
***ER 96* Energy Forecasts**
Planning Area and Statewide
(GWh)

[this is table 7 from demand forecast order]

Before comparing system supply and demand, exports and reserve requirements must be added to the end-use requirements. **Table 5** shows the statewide annual system capacity requirements which include transmission and distribution losses, out-of-state bulk power exports, and capacity reserve requirements. Capacity reserves are calculated assuming current reserve margin planning targets of about 15 or 16 percent, depending on the utility. The statewide capacity requirements reflect a summation of the state's individual utility service area requirements (except for the California Department of Water Resources, whose load diversity makes it problematic to include in a statewide total).

Table 5
Statewide Annual System Capacity Requirements
(includes losses, exports and reserve requirements)

	2000	2003	2007	2015
System Capacity Requirements (MW)	64,478	67,505	71,284	78,019

Attachment 1 of this testimony includes the detailed accounting of the system capacity requirements for each utility service area. [Note: capacity requirements include reserve requirements, the amount of which varies slightly with the amount of nondispatchable conservation and load management assumed. Capacity reserves are not provided to back up resources to meet the increment of forecasted demand that is expected actually to be avoided through nondispatchable conservation and load management programs. The system capacity requirements shown in Table 5 reflect the "Business As Usual" level of uncommitted DSM.]

Statewide Existing And Committed Supply Levels

Capacity requirements of the state's utilities are served by a variety of supply resources--utility-owned plants, purchases from PURPA qualifying facilities (QFs), self-generators, and inter-utility bulk power transfers. **Table 6** shows the statewide total of these resources that are either existing or committed to California utilities.

Table 6
Statewide Annual Existing and Committed Capacity Resources
(excludes capacity from long-term reserve or decommissioned plants)

	2000	2003	2007	2015
System Capacity Resources	58,223	57,437	56,041	52,413

Existing and Committed supply resources are insufficient to meet expected system capacity requirements in any year. Staff does not, however, define this shortfall as the system deficit. Rather, we first estimate the amount of uncommitted resources likely to occur even if no commitment has been made. These uncommitted resource fall into two broad categories, uncommitted demand-side management and spot capacity.

Satewide Ucommitted Demand Side Management (DSM) Levels

Table 7 shows the levels of expected savings from the three Uncommitted DSM scenarios. These savings include end use and transmission loss savings from conservation, non dispatchable load management and dispatchable load management programs.

The Declining DSM scenario reflects a continuing decline in DSM expenditures. For this scenario, we assume that a surcharge does not get enacted or established. The reduction in public spending, along with the uncertainty of restructuring and potentially lower variable prices reflecting rate design changes, imply no additional private market savings beyond those incorporated in the demand forecast.

The Business As Usual With Spillover Effects scenario reflects funding continuing at the already reduced 1996 levels and estimates of spillover savings. In this scenario we assume that a surcharge gets adopted and implemented at current funding levels. Because of the increasing emphasis on program spillover, development of the ESCO industry, and the increased emphasis on private-market (Track 1) DSM activities, Staff included estimates of the spillover effect of public programs on the private market in this scenario.

In the Restored Funding With Spillover Effects scenario, we assume a surcharge is adopted and funding is restored to 1994 levels by 1999 and stays at that level, with the same rate of spillover as in the Business As Usual With Spillover Effects scenario. Staff also has developed a methodology to begin estimating savings from market transformation programs. Staff is describing these savings estimates in the forthcoming Staff Report on DSM, but believes that our market transformation estimates are not sufficiently developed to be useful for IAN in ***ER 96***.

Table 7
Statewide Uncommitted Demand-Side Management Levels
Conservation, Nondispatachable and Dispatchable Load Management
Including Loss Savings

	2000	**2003**	**2007**	**2015**
Declining DSM	3558	3189	2974	2586
Business As Usual	4431	5126	6316	8204
Restored Funding	4900	6128	7980	10676

Statewide Other Uncommitted Resources

Historically, California utilities have relied on surplus capacity from both the Pacific Northwest and Desert Southwest to economically meet a portion of statewide capacity requirements. California and the Pacific Northwest share considerable load and resource diversity, which makes bulk power purchases and exchanges an economically attractive resource option for both regions. Temporary capacity surpluses in the Desert Southwest have been purchased by California utilities in the past and continued purchases are expected in the future. However, since there is no load diversity between California and the Desert Southwest, the capacity surplus available to California is expected to diminish over time. Staff includes in its supply and demand balance an expected continued reliance on an amount of spot capacity purchases or exchanges, primarily from the Pacific Northwest. This amount is about 3,000 MW, which is assumed to be available primarily to Pacific Gas & Electric and Southern California Edison Companies. Additional amount of spot capacity could be available to other California utilities, although none were counted in the staff's supply demand balance.

Statewide Balance Of Supply And Demand

Table 8 shows the statewide balance of electricity supply and demand under each of the three scenarios of expected Uncommitted DSM savings. Under the Declining DSM scenario, state-wide capacity deficits occur by the year 2000, reaching almost 5,000 MW by the year 2003 and more than 10,000 MW by the year 2007. Under the Business As Usual DSM scenario, state-wide capacity deficits are delayed beyond 2000 but reach about 2,500 MW by 2003 and 6,500 MW by 2007. Under the Restored Funding DSM scenario, statewide capacity deficits are only about 1,400 in 2003 and about 4,600 in 2007.

As stated in the Summary section above, these apparent deficits should not be interpreted to mean that significant power plant building programs must begin immediately. Our accounting of the amount of supply resources available to the state's utilities is fairly conservative. Only resources currently committed to a utility are counted. The current western regional market has capacity resources available to California utilities which have not been included.

Table 8
***ER 96* Statewide Capacity Supply and Demand Balance**
Under Three Scenarios of Expected Uncommitted DSM Savings
(MW)

Service Area Balance Of Supply And Demand

The following section provides a description of the supply and demand balance in the individual utility service areas. It also provides a brief discussion of various supply issues of interest in the various service areas.

Pacific Gas and Electric Planning Area

The Pacific Gas and Electric Planning Area encompasses all resources owned by the Pacific Gas and Electric Company (PG&E), the Western Area Power Administration, the City and County of San Francisco, several small irrigation districts and a number of smaller utilities. This includes all generation by the above, all power purchased or imported by any of the above, and all contractual obligations between any of the above entities. Contracts with municipal utilities outside the planning area are treated as exports: Sacramento Municipal Utility District, Modesto Irrigation District, Turlock Irrigation District, Redding, the City of Santa Clara and Northern California Power Agency.

PG&E's business plans are undergoing change to better the prospects of competing successfully in the restructured market. In supply forms filed in April 1996, the company restated that it has no plans to add new utility-owned generation through 2003 and will instead meet demand growth with a combination of existing generation, in-area purchases, imports, and aggressive DSM programs. The company believes that "the emerging competitive electric industry will result in appropriate pricing signals for the addition of new generating resources."

The utility has a diverse mix of generation technologies, including nuclear, hydro, geothermal, steam, combustion turbines, and wind. The following paragraphs provide a brief comparison of the resource information supplied to the Commission in PG&E's supply forms from ***ER 94*** to ***ER 96***.

<u>Generation</u>

- Diablo Canyon I and II

The nuclear units of the PG&E system, have continued to be profitable for the utility. Negotiations are underway to adjust power prices and to accelerate depreciation of the plant.

- Oil and Gas Plants

PG&E stated that 12 power plants (1342 MW) were retired in 1994, but did not list the plants individually.[2] Staff believes the plants include Contra Costa 1-5, Kern 1-2, and Moss Landing 1-5. Several of these plants were designated for long term reserve before the ***ER 94*** cycle, others were scheduled for long term reserve in 1995, still others were expected to stay on line until 2000. The dates from the ***ER 94*** Supply Forms are listed as follows:

Contra Costa 3	long term reserve
Kern 1-2	long term reserve
Moss Landing 1-2	1995
Contra Costa 1-2	1995
Moss Landing 3	1995
Contra Costa 4-5	2000
Moss Landing 4-5	2000

In their Form 10K filing with the Securities and Exchange Commission dated December 31, 1994, the company states that 12 fossil fuel steam plants were retired in place. Staff has no information stating that the company has surrendered the operating permits for these units, and staff believes that these units could be reactivated if it made good economic sense.

- Qualifying Facilities (QFs)

Since ***ER 94***, the amount of QF firm capacity has increased from 2847 MW to 2882 MW. The forecast shows a gradual increase in QF firm capacity through 1999, at which time it levels off and remains constant throughout the time horizon.

There are some changes which may affect that forecast in the near future. Some of the QFs have been purchased by other firms, some have gone out of business, and others have been bought out by PG&E. Staff hasn't determined the amount of capacity that may still be available to the market. It was reported in the utilities' 1995 reasonableness review case pending before the CPUC, however, that PG&E bought out nine qualifying facilities totaling 130 MW. The utility paid $92.6 million for these SO4 contracts. The utility estimated the savings should be at least $121 million, and the net present value should fall between $109 and $176 million.[3]

- Imports

PG&E also relies on long-term seasonal exchanges from the Northwest, daily exchanges, and spot capacity to meet its load. The continued availability of imports from the Northwest has been a topic of intense discussions in light of restructuring. The discussions are ongoing.

- Sale of PG&E Generation Facilities

PG&E has attempted to sell a number of smaller hydro plants that are due for relicensing and need repair. For example, El Dorado Irrigation District (EID) has purchased Project 184 from PG&E for $500,000 at close of sale and $1.5 million by 2003. The system will require $4.5 million in repairs which EID has agreed to do. The system includes four mountain lakes, 22 miles of canals and a powerhouse. If the sales agreement isn't approved, PG&E will reimburse EID for the expense.

Utility Bypass

A number of PG&E's customers are seeking power generation from other suppliers who offer lower prices. To date only one of these customers, Foster Farms, has executed a contract and received power from an alternate supplier, Merced Irrigation District (Merced). This is a new direction in the market for Merced.

Other irrigation districts in the utility's planning area are also negotiating with PG&E's customers.

The board of directors of the Bay Area Rapid Transit (BART) decided in May of 1996 to sign a 20-year contract for power with BPA and Western. BART expects to save $9 million per year, which could ultimately mean a savings of $200 million. Under the new agreement to be signed in June, BPA will provide 90 percent of BART's power instead of the 6 percent it now supplies. BART is the first transit authority in the nation to switch power suppliers.

BART has been one of PG&E's larger customers, consuming about 70 MW per year at a cost of around $21 million. The transit system has been looking at alternate sources of power for the last three years, but was unable to enter into such an agreement until Senate Bill 184 was passed last October. Under that legislation, PG&E must wheel power from any suppliers like Western to any location on the system it serves and charge wheeling rates. BART still needs to negotiate a transmission agreement with PG&E. Under the agreement, BART will eventually be able to access up to 55 MW from Western and 90 MW from BPA. PG&E would then supply only 5-6 percent of the transit's demand.

Demand Side Management Scenarios

In ***ER 94***, PG&E had a target reserve margin of 15.5 percent, and this is the same one used for ***ER 96***. Based on the firm capacities reported in the ***ER 96*** Supply Forms, the utility would be short of adequate capacity by 1999 without demand side management.

PG&E Supply and Demand Balance

Table 9 shows the supply and demand balance for the PG&E planning area under the three scenarios of Uncommitted DSM. Under the Declining DSM scenario, capacity resources fall below the 15.5 percent reserve planning target in 2002 and by 2003 the deficit is 820 MW, growing to 2,793 MW by 2007. Under the Business as Usual DSM scenario, significant deficits don’t occur until about 2004, increasing to 1,400 MW by 2007. Under the Restored Funding DSM scenario, deficits begin in 2005 and grow to only 764 MW by 2007. Further details of the PG&E supply and demand balance are provided in **Attachment 1**.

Table 9
PG&E Capacity Supply and Demand Balance
(MW)

Northern California Municipal Utilities

Existing Northern California municipals are focusing on short-term planning and remaining flexible in order to respond to evolving industry conditions. They each emphasize that it is important for the municipals not to be excluded from sharing in any of the future benefits of restructuring. It is also important to them that they retain their current customers, since unexpected demand reductions would negatively impact utility operation and efficiency. (For the long term, it is vital that they not lose their access to low-cost power through any future pressure for divestiture of existing Federal power projects.)

None of the Northern California municipals has reported plans to participate in the construction of new generation facilities, either during the expected effective dates of ***ER 96*** or during the following several years.

Each of the Northern California municipals has available transmission capacity on their portions of the California-Oregon Transmission Project (COTP). This can be used for short-term or spot purchases, or to enter into or extend bilateral contracts or pooling arrangements. Although the municipals have long-term contracts in effect that will supply power into the future, some of these existing long-term contracts may have to be renegotiated in order to remain competitive.

Sacramento Municipal Utility District (SMUD)

Table 10 shows the supply and demand balance for the SMUD planning area under the three scenarios of Uncommitted DSM. Under the Declining DSM scenario, capacity resources fall below the 15.5 percent reserve planning target in 2002 and by 2003 the deficit is 820 MW, growing to 2,793 MW by 2007. Under the Business as Usual DSM scenario, significant deficits don't occur until about 2004, increasing to 1,400 MW by 2007. Under the Restored Funding DSM scenario, deficits begin in 2005 and grow to only 764 MW by 2007.

The Commission's ***ER 96*** adopted demand forecast for SMUD is 6.6 percent lower by 2007 than was the forecast for ***ER 94***. SMUD's uncommitted DSM forecast (in the Business-As-Usual scenario) for the same year is only 34 percent of the ***ER 94*** forecast (235 MW for ***ER 96***, as opposed to 681 MW for ***ER 94***).

SMUD's resources are also somewhat changed for ***ER 96***. The SMUD Geo plant is now expected to cease production as of 2005 (for ***ER 94***, its capacity was 19 MW in 2007); at the same time, SMUD's share of the CCPA geothermal units has been reduced by half (15 MW in 2007, rather than 28 MW). (The future viability of the CCPA units is scheduled to be decided by the co-owners' Joint Powers Commission on June 26, 1996.) A larger change is SMUD's recently announced termination of its plans for the Sacramento Ethanol Project, which in ***ER 94*** was expected to produce a dependable capacity of 149 MW, starting in 1997. SMUD cites the reason for termination as unfulfilled developer contractual obligations.

Table 10
SMUD Capacity Supply and Demand Balance
(MW)

Also terminated recently is the second phase of the Solano Wind Farm development, due to continuing financial problems of Kenetech, the developer. SMUD staff has indicated that the District still intends to use the site for a future wind resource, but will be seeking a different developer. SMUD has also recently issued an RFP to identify and possibly acquire up to 50 MW of renewable resources, with project proposals due on July 26, 1996. Additionally, SMUD is working on future plans for distributed generation and for other, perhaps smaller cogeneration projects, which could be located in conjunction with industrial or commercial processes.

In each of the three ***ER 96*** DSM scenarios, a capacity deficit has already appeared in 1996; the actual reserve margins also fall below the target reserve margin percent in 1996. On its share of COTP, SMUD currently receives a 40 MW delivery from Snohomish Public Utility District through 2007. SMUD still has 225 MW (before losses) available on COTP to use for a variety of purchases.

NCPA, the Cities of Santa Clara and Redding, and Turlock Irrigation District (TID)

The following is a summary resource issues of interest to the listed municipal utilities. Please see **Table 11** and the individual utility capacity accounting tables in **Attachment 1** for additional details.

NCPA: The Commission's ***ER 96*** adopted demand forecast for NCPA is 2.3 percent lower by 2007 (the end of the 12-year ***ER 96*** assessment period) than was the forecast for the preceding Electricity Report. NCPA's uncommitted DSM forecast for the same year is only 19 percent of the ***ER 94*** forecast. Its resources remain the same as ***ER 94***, except that the NCPA geothermal units' production forecast has actually improved. In 2007, the forecasted geothermal capacity is double that of ***ER 94*** (45 MW for NCPA's share, compared with 21 MW for ***ER 94***). Despite the overall continuing geothermal steam resource decline, NCPA is managing the units well and injecting additional water from an outside source to augment vapor pressure.

Table 11
Small Municipal Utility Supply and Demand Balance

NCPA's actual reserve margin first falls below the target reserve margin percent in 2003. On its share of COTP, NCPA currently receives a 56 MW delivery from Seattle City Light and a 30 MW delivery from Washington Water Power. NCPA still has 40 MW (before losses) of transmission access available on COTP.

City of Santa Clara: The Commission's ***ER 96*** adopted demand forecast for Santa Clara is 2.0 percent lower by 2007 than was the forecast for ***ER 94***. Santa Clara's uncommitted DSM forecast for the same year is only 30 percent of the ***ER 94*** forecast. Its resources remain the same, except for the geothermal forecast. Santa Clara's share of the NCPA geothermal units has doubled (from 18 MW to 36 MW in 2007); at the same time, Santa Clara's share of the CCPA geothermal units has been reduced by half (6 MW in 2007, rather than 3 MW). (The future viability of the CCPA units is scheduled to be decided by the co-owners' Joint Powers Commission on June 26, 1996.) Santa Clara feels particularly vulnerable to the effects of industry restructuring, since it has largely an industrial load. Utility staff have indicated that they have been making efforts to retain their current customers by means of individual contractual agreements for competitive rates.

Santa Clara's actual reserve margin first falls below the target reserve margin percent in 2004. On its share of COTP, Santa Clara currently receives a 49 MW delivery from BPA. Santa Clara still has 200 MW (before losses) of transmission access available on COTP.

The City of Redding: The Commission's ***ER 96*** adopted demand forecast for Redding is 21.6 percent lower by 2007 than was the forecast for ***ER 94***. Redding's uncommitted DSM forecast for the same year is only 19 percent of the ***ER 94*** forecast. Its resources remain the same, except that Redding recently signed a pact with PacifiCorp for a seasonal energy-only exchange from December of the year 2000 through November 2015. PacifiCorp will receive energy in New Mexico from Redding's share of the San Juan Unit 4 coal plant, and deliver energy from its system to Redding at the California-Oregon border. (This arrangement extends PacifiCorp's influence in the Southwest, in keeping with its announced strategy to pursue nation-wide deals.) Redding's April 10, 1996 supply-side filing shows the possible future addition of three 45 MW combustion turbines -- one in 2007, another in 2011 and the last in 2015. Redding staff have indicated that these new generating units would most likely be built at the same location as Redding Power, which has been operating since 1995.

Redding's actual reserve margin first falls below the target reserve margin percent in 2006. On its share of COTP, Redding currently receives a 47 MW delivery from PacifiCorp and a 21 MW delivery from BPA. Redding will regain its 25 MW (before losses) of COTP access that is currently being used by Western, starting in August of 1998.

Turlock Irrigation District: The Commission's ***ER 96*** adopted demand forecast for TID is 8.7 percent lower by 2007 than was the forecast for ***ER 94***. Its resources remain essentially the same, except that TID's share of the output from one of the NCPA geothermal units has nearly doubled (in 2007, from 3 MW in ***ER 94*** to 5 MW for ***ER 96***). Additionally, TID's April 23, 1996 supply-side filing indicated that TID's 47 MW delivery from LADWP (Palo Verde to Midway) has now been extended into the next century. In ***ER 94***, this delivery terminated after 1999; now it continues from the year 2000 through 2011.

TID's actual reserve margin first falls below the target reserve margin percent in the year 2000. On its share of COTP, TID currently receives a 17 MW delivery from Washington Water Power/BPA and a 50 MW delivery from Pacific Northwest Generating Cooperative. TID still has 35 MW (before losses) of transmission access available on COTP. In 2005, TID's available COTP transmission will increase again to 85 MW when Western returns the 50 MW portion it now uses.

Modesto Irrigation District (MID)

The Commission's ***ER 96*** adopted demand forecast for MID is 1.5 percent higher by 2007 than was the forecast for ***ER 94***. MID's uncommitted DSM forecast for the same year is only 10 percent of the ***ER 94*** forecast. Its resources remain essentially the same, except for the geothermal forecast. MID's forecasted share of the CCPA geothermal units has been reduced by nearly 40 percent in 2007 (from 19 MW in ***ER 94*** to 12 MW for ***ER 96***). (The future viability of the CCPA units is scheduled to be decided by the co-owners' Joint Powers Commission on June 26, 1996.)

MID's actual reserve margin first falls below the target reserve margin percent in 1997. On its share of COTP, MID currently receives a 70 MW delivery from BPA and a 24 MW delivery from Portland General Electric, which increases to 48 MW for 1997, according to MID's April 24, 1996 supply-side filing. MID still has 140 MW (before losses) available on COTP. After the Portland delivery terminates (by the year 2000) MID's available COTP capacity increases to 190 MW. If MID's full COTP allocation were to be used for purchases, a capacity deficit would not appear until 2002. In addition, MID has access to 102 MW of transmission capacity South-of-Tesla to Midway.

Under authority granted to irrigation districts through the California Water Code (§ 22115 and § 22120), MID has been purposefully pursuing customers that historically belonged to PG&E, using the promise of lower rates to attract their interest. MID has already entered into agreements with two small cities (Escalon and Ripon) and is considering building a distribution system to parallel PG&E's local system if no agreement can be reached with PG&E to acquire the existing facilities. In addition, MID has already purchased a substation from Praxair Corporation in order to facilitate delivery of lower-cost power to Praxair from Destec, an independent power producer. Other industrial customers, such as Dow Chemical and Westinghouse, could potentially be lured away from PG&E's territory in the future. MID appears to be moving quickly in order to pre-empt impending decisions addressing transition charge penalties. MID also won the recent bid to facilitate Foster Farms' receiving electric service from Merced Irrigation District (which is acting as the retailing agent), with wheeling services provided by TID and the power originating either from the Northwest or from Enron, another independent power producer.

Merced Irrigation District

To staff's knowledge, neither supply nor demand filings have been received from the District as of this date. Merced Irrigation District's loads and resources have previously been included within the PG&E Planning Area.

Merced recently acquired Foster Farms, which was formerly served by PG&E, as a new electric customer. According to Merced staff testimony at the Commission on June 11, 1996, Merced's active solicitation of others' customers is fundamental to planning for its own future. Merced owns 2 hydroelectric plants, the output of which is leased to PG&E until 2014, when both units are scheduled to undergo Federal re-licensing procedures. To prepare for continuing operation and taking over the units' production in 2014, Merced intends to develop a substantial customer base, attracted by the District's low rates, and to make enough money to both acquire distribution and to amass a reserve fund for hydro re-licensing. To these ends, Merced is pursuing among others, additional industrial customers, the city of Livingston and potential developers for the now-closed Castle Air Force Base.

Southern California Edison Planning Area

The CPUC's Decision of December 20, 1995, ordering restructuring the electric utility industry in California, as of January 1, 1998, has created much uncertainty. Consequently, Southern California Edison Company has not developed resource plans since ***ER 94***. Prior to divestiture of any of its resources, Edison believes it has enough capacity to meet its resource requirements, including a planning reserve of 16 percent, through year 2004. The reasonableness of some of the assumptions used in creating the capacity resource accounting tables can be questioned in a restructured, competitive business environment. Assumptions likely to change include the reserve margin and the availability of spot capacity and economy energy.

Edison is not certain of the system operating procedures after the formation of an independent system operator and a power exchange. Significant changes in ownership of generating assets may occur. The company filed a voluntary divestiture plan with the CPUC for 50 percent of its in-basin fossil units. It is awaiting approval of this plan. Ownership and operation of these units after divestiture remains an uncertainty. Other uncertainties include electricity demand, generation and transmission capacity, environmental regulations affecting supply, and the behavior of the competitive electricity market.

Similarly, the company states they have an inability to accurately predict future electricity market prices for the new generation market.

Edison's submittal of supply-side data was in two parts. Part I, filed April 11, 1996, constituted historical data with minor updates to the 1994 data for Environmental Pollutants, and Transmission Data. Part II, filed May 15, 1996, provided a copy of Edison's Dependable Operating Capacity of Resources. This report details committed resources to serve load as of December 31, 1995. Part II also contained a description of the utility's plan for the pendency of ***ER 96*** and a discussion of the criteria used to develop the plans. A summary of these changes and CEC staff observations follows.

This ***Electricity Report*** forecasts slight increases in capacity requirements over ***ER 94*** levels. One major change from ***ER 94*** is the movement of 895 MWs of short-term reserve capacity into the active oil and gas category and the inclusion of these units in calculating the reserve requirements.

Another change deals with the assumption of public power utilities' self-resourcing. An assumption regarding the extent of Public Power Utility (PPU) reliance on partial requirements purchases from Edison is needed for ***ER 96***. Edison is required to meet resource needs that the PPUs either cannot or choose not to meet themselves. Hence, the forecasted resource needs for the Public Power Utilities will directly impact the resource needs for Edison. The Public Power Utilities have said they intend to 100 percent self-resource. Azusa has even recently filed with the CPUC stating that they have "made Edison fully aware in writing as early as February 1992 of its intention to provide electric service to all customers located within the city limits".

The position that the PPUs will self-resource for all, or nearly all, of their incremental needs is supported by historical data, the incentives faced by the PPUs, and the PPUs themselves. The fraction of total energy requirements purchased under the partial requirements tariff by the PPUs has declined from 100 percent in 1980 to 6.5 percent in 1993. Currently, the PPUs are able to obtain power at lower cost than the rates charged under Edison's partial requirements tariffs by self-resourcing. With this and restructuring around the corner, staff has assumed for ***ER 96*** the public power utilities will 100 percent self-resource. This is a change from ***ER 94***; in which we assumed self-resourcing to be at 89.7 percent.

- Uncommitted DSM

There is much uncertainty about the future of DSM programs. Edison worked with Commission staff in the development of alternate DSM scenarios for the future. Uncommitted load management programs are also facing an uncertain future. It is Edison's position that the currently achieved level of load management programs, 2,004 MW, should be held constant through 2007.

- BRPU Resources

Edison reached settlement agreements with all the winning bidders of the BRPU. Most of these contracts were bought out; a few (Kenetech, Air Products and US GenCo.) have options to build at more reasonable prices than those originally in the BRPU, but no obligation to go forward. The maximum capacity from these would be 478.6 MW. The one exception to this is the first block of Kenetech capacity, 37.5 MW nameplate, which is at Kenetech's option to build. Edison would have to purchase this at a price close to today's competitive market price.

However, the options would only be exercised if the energy price was less than the market clearing price, in which case it is reasonable to assume that the new company would build and sell to the power exchange instead of to Edison. Edison would be unlikely to request to have these resources built. Therefore, staff has assumed no new generation from BRPU resources will be built during the planning period. This represents a reduction of 684 MW of pending BRPU resources from ***ER 94*** levels.

- Spot Capacity

We have assumed the same level of spot capacity in the accounting tables for this ***Electricity Report*** as we did in ***ER 94***. However, it is likely that after the formation of an ISO/PX this cheap resource would vanish for the utility and the suppliers would sell directly to the PX at market clearing prices. Removal of this 400 MW resource will accelerate the year the utility reaches a deficit. However, the resource will not dissipate; it will most likely just be more expensive and available from the PX.

- Generic Pacific Northwest Exchange

We have assumed the same level of spot capacity in the accounting tables for ***ER 96*** as we did for ***ER 94***. This 188 MW assumed generic resource can be considered a proxy for purchases and sales through the ISO/PX, as with spot capacity purchases.

- Planned Transmission Facilities

Two planned projects identified in CFM X, Devers-Palo Verde 2 and Kramer-Victor Nos. 1 and 2 have been cancelled. The Devers-Palo Verde 2 project would have provided an additional 1200 MWs of interstate transmission capacity. The Kramer-Victor project would have provided about 1200 MW of capacity for qualifying facilities in the Mohave Area of California.

- Retirements

SONGS 2 and 3 will be retired during the 20-year planning horizon. The license for SONGS 2 expires August 8, 2013. Staff has therefore removed the capacity of this plant in our accounting of resources for year 2013, since it would not be available for Edison's September peak. However, should the company run the plant until August of 2013 it would obtain an extension and run the plant through the remainder of the year. SONGS 3 is retired the following year.

Edison Planning Area Supply and Demand Balance

Table 12 shows the supply and demand balance for the Edison planning area under the three scenarios of Uncommitted DSM. Under the Declining DSM scenario, capacity resources fall below the 15 percent reserve margin target before 2003 with deficits increasing to 2,322 MW by 2007. Under the Business As Usual DSM scenario, capacity deficits don't occur until after 2004, growing to 571 MW by 2007. Under the Restored Funding DSM scenario, capacity deficits begin only after the year 2007.

Other Edison Issues

- Target Reserve Margin

The current planning has Edison using a reserve of 16 percent. After the formation of a power exchange it is anticipated that the ISO and not the utility will have the responsibility of carrying reserves for reliability. One of the advantages of the competitive environment is that consumers will have a choice of the level of reliability they desire and want to pay for. Therefore, it would be reasonable to assume that the reserve margin the ISO would carry would be a lower percentage than the current 16 percent. The reserve margin would probably be somewhere between WSCC criteria of the greater of seven percent or single largest contingency and current levels, depending on customer choice.

- Air Quality

Since the filing of Common Forecasting Methodology X (CFM X) forms for ***ER 94***, Edison has installed, begun operation, and tested the performance of selective catalytic reduction (SCR) NOx emission controls on nine boilers. This has resulted in a reduction of the NOx Rate below that anticipated in the ***ER 94*** forecast for five of the nine units. The NOx rate was anticipated to be 0.15 lbs/MWh after receiving SCR retrofits on Alamitos Units 5 & 6, El Segundo Unit 4, and Redondo Beach Units 7 & 8. Operation and testing of these units revealed the actual NOx Rate to be 0.125 lbs/MWh.

Additional Selective Catalytic Reduction (SCR) equipment for NOx reductions may be installed in the future depending on the development of the RECLAIM market in the South Coast Air Quality Management District (SCAQMD), and in particular, on the price of the RECLAIM Trading Credits. Currently, Edison has no plans to retrofit additional plants with SCR.

Table 12
Edison Planning Area Capacity Supply Demand Balance

Small Public Power Utilities of Southern California

The following is a summary resource issues of interest to the listed municipal utilities. Please see **Table 11** and the individual utility capacity accounting tables in **Attachment 1** for additional details.

City of Anaheim

Anaheim operates under an Integrated Operations Agreement (IOA) with SCE. This agreement affects how Anaheim purchases capacity and energy. In its 1995 Public Utilities Annual Report, Anaheim acknowledges that competition in the electricity sector will require the utility to be "technologically advanced and financially strong, professionally managed and most of all, responsive to customers."

Cutting costs is paramount to Anaheim, which plans to reduce its maintenance expenditures by $2.1 million over six years. There are no near-term plans to add any new generation. Instead, the utility will phase out high cost generation and aggressively pursue new energy purchases from the emerging.marketplace.

According to its May 1996 filing, Anaheim anticipates capacity shortfall around 1998. According to Staff CRATs table (using CEC demand data), Anaheim starts in 1996 with a deficit of 14 and ends in 2015 with a deficit of 529. Anaheim plans to work with Edison and others to meet its forecasted native load requirements. It will continue to purchase power by contract and will likely purchase through the PX as necessary .

Per Anaheim's May 1996 filing,: uncommitted DSM programs are currently undergoing changes and reevaluations. Program costs estimates and participation estimates are not available pending reevaluation. Anaheim's fallback position is to use ***ER 94*** DSM numbers for ***ER 96***.

City of Riverside: Riverside operates under an Integrated Operations Agreement (IOA) with SCE. This agreement affects how Riverside purchases capacity and energy. In its May 1996 filing, Riverside indicates that due to electric utility restructuring, a new long-term forecast was not prepared. Instead, an interim supply plan was developed which reflects only short term strategies of purchasing power from the emerging market.

According to its May 1996 filing, Riverside anticipates capacity shortfall around 2003. According to Staff CRATs table (using CEC demand data), Riverside starts in 1996 with a deficit of 81 and ends in 2015 with a deficit of 548. Riverside plans to work with Edison and others to meet its forecasted native load requirements. It will continue to purchase power by contract and will likely purchase through the PX as necessary .

Per their May 1996 Supply Forms Filing, uncommitted DSM programs are currently under-going changes and reevaluations. Program costs estimates and participation estimates are not available pending reevaluation.

City of Azusa: All Azusa resources are integrated into the SCE system. In its May 1996 filing, Azusa indicates that due to electric utility restructuring, a new long-term forecast was not prepared. Instead, an interim supply plan was developed which reflects only short term strategies. Azusa plans to meet its short term and medium term resource needs by purchasing surplus power from other entities in the marketplace, as opposed to building and/or committing to additional generation projects.

According to its May 1996 filing, Azusa anticipates capacity shortfall around 2003. According to Staff CRATs table (using CEC demand data) Azusa starts in 1996 with a surplus of 9, has first deficit of 15 in 2003 and ends in 2015 with a deficit of 33. Azusa plans to work with Edison and others to meet its forecasted native load requirements. It will continue to purchase power by contract and will likely purchase through the PX as necessary .

Cities of Banning, Colton and Vernon: The cities of Banning, Colton, and Vernon did not provide fully detailed ***ER 96*** filings. In each case, these municipal utilities cited the uncertainty due to the restructuring of the electric industry as the reason for not developing new long term resource plans and requested instead that their filings from ***ER 94*** be used. This was one of the options offered to all utilities. Vernon has provided a formal letter to this effect. As of June 10, 1996, no written comment or data have been received from Banning or Colton.

San Diego Gas & Electric Planning Area

The ***ER 96*** resource assessment for SDG&E can be divided into two phases; pre-and post restructuring, more specifically, pre-and post ISO/PX operation. The ISO/PX is presently scheduled to begin operation starting January 1, 1998.

SDG&E's near-term strategy is to rely on short-term power purchases to augment both existing resources and existing firm contracts in meeting its resource requirements. After the start of restructuring, SDG&E will purchase on behalf of its electricity customers, all power needs from the ISO/PX. Near-term, 1996-1997, SDG&E plans on carrying net capacity reserves close to their planning reserve margin of 15 percent over total peak planning load. Post ISO/PX operation, SDG&E believes a planning reserve level will no longer be their responsibility.

With respect to a comparison of the existing system from an ***ER 94*** and ***ER 96*** perspective, there are only small changes. SDG&E reports an increase in utility-owned oil and gas steam generation capacity from 1619 MW to 1641 MW due to steam path replacement work performed in 1994. Firm capacity from non-utility owned resources shows an increase of 121 MW in 1998 from ***ER 96***, compared to ***ER 94***. Thus the net change in firm capacity is an increase of 143 MW in 1998 when comparing ***ER 96*** to ***ER 94***.

SDG&E has no current plans to repower any of its existing generating units. As such, several transmission projects associated with the South Bay 3 Repower project have been canceled. Additionally, SDG&E has no plans to construct or purchase any BRPU resources.

Assumptions on schedules to retrofit existing utility-owned oil and gas steam generation boiler units to comply with air quality regulation have changed from ***ER 94*** to ***ER 96***. Specifically, the San Diego County Air Pollution Control District (APCD) has revised their Rule 69 to allow SDG&E more flexibility in meeting the APCDs' NOx emission reduction goals. SDG&E was to have filed a compliance plan with the APCD on June 9, 1996.

<u>SDG&E Supply and Demand Balance</u>

Table 13 shows the supply and demand balance for the SDG&E planning area under the three scenarios of Uncommitted DSM. Under the Declining DSM scenario, capacity resources fall below the 15 percent reserve margin target in every year, growing to a deficit of 1,808 MW by 2003. Under the Business As Usual DSM scenario, capacity deficits still occur every year but are reduced to 1,572 by 2003. Under the Restored Funding DSM scenario, the year 2003 capacity deficits are reduced slightly more to 1,502 MW.

City of Los Angeles Department of Water and Power

Industry-wide restructuring has caused the Los Angeles Department of Water & Power (LADWP) to deal with uncertainty in much the same manner others are; they are searching for ways to position themselves competitively by being more energy efficient and offering their customers better rates. While it will not be mandatory that municipal utilities turn facilities over to the Independent System Operator (ISO), "...LADWP must compete, at least indirectly, with prices and standards for service set by the market." [4] LADWP feels that restructuring will lead to local concerns being set aside in favor of market-setting mechanisms which will "reduce options of the City Council when setting rates in general...and reduce their ability to divide income requirements between customer classes." Increasing levels of uncertainty has prompted LADWP to shift their focus from various capital expenditures to efforts on increasing customer service and reliability.

The ***ER 96*** planning period (1996-2015) shows the Los Angeles Department of Water & Power with 6,743 MW of available utility-owned capacity including 368 MW of nuclear, 4,751 MW of coal/oil, and 1,247 MW of pumped storage. Contractual imports add another 590 MW to 670 MW. Please see **Attachment 1** for details.

Table 13
SDG&E Capacity Supply and Demand Balance
(MW)

LADWP Supply and Demand Balance

Table 14 shows the supply and demand balance for the LADWP planning area under the three scenarios of Uncommitted DSM. For ***ER 96***, demand has fallen from ***ER 94*** between 5 percent and 10 percent through the year 2013. That results in a slightly larger surplus from ***ER 94*** over the 20 year ***ER 96*** planning period. All three DSM scenarios, show LADWP with enough committed plus uncommitted DSM resources to satisfy demand through the year 2011 when LADWP should experience a deficit between approximately 35 and 160 MW, depending upon DSM scenario.

In updating the ***ER 96*** resource account tables, staff maintained the ***ER 94*** 20 percent target reserve margin throughout the ***ER 96*** planning period. This level, however, may be too high. In a restructured environment, participation either in the market or with a Regional Transmission Group will likely lead to target reserve margins falling to levels significantly lower than current ones. A reduction in the reserve margin will have the effect of having a surplus further into the planning period.

LADWP is focusing on industry uncertainty. It has been working on measures to retain large industrial customers and improve revenue growth by becoming more energy efficient and competitive through cooperatives with power marketers. They have formed a new marketing and business planning unit to focus on keeping costs competitive and maintaining large industrial customers, including trying to bring back those who opted for self-generation. Additionally, LADWP's 1995-1996 budget resulted in putting off building a proposed transmission line into Canada that would by-pass Bonneville Power Administration. They have also substituted some other capital expenditures for increases in spending on those items that would improve service reliability.

Additionally, LADWP has issued a Request for Qualifications (RFQ) seeking partners for help in managing the utility and marketers to lock in surplus power agreements. Additionally, the DWP has reached an agreement with CALPINE to develop up to 150 MW of geothermal power and two other agreements with power marketers to market LA surplus electricity.

Cities of Burbank, Glendale and Pasadena

The following is a summary resource issues of interest to the listed municipal utilities. Please see Table 11 and the individual utility capacity accounting tables in Attachment 1 for additional details.

The ***ER 96*** draft capacity accounting resource tables shows total capacity between 389 MW and 339 MW for Burbank, 391 MW for Glendale, and 361 MW and 350 MW for Pasadena. Approximately 80 percent of their resources are utility-owned. Please see ***ER 96*** capacity resource accounting tables for details.

Table 14
LADWP Capacity Supply and Demand Balance
(MW)

Neither Burbank, Glendale, nor Pasadena had any nondispatchable DSM for ***ER 96***. See the ***ER 96*** resource accounting tables for detail. Pasadena will show no deficit throughout the ***ER 96*** planning period. Burbank has enough capacity to meet demand through the year 2013 when they will experience a 13 MW deficit. Glendale shows a deficit beginning 2006 with 2 MW. All three have actual reserve margins above 15 percent and as high as 45 percent for Pasadena.

Burbank, Glendale, and Pasadena are concerned about keeping competitive and reducing debt. Pasadena has cut the city's contribution in an effort to help reduce debt.

Imperial Irrigation District (IID)

Table 15 shows the supply and demand balance for the IID planning area under the three scenarios of Uncommitted DSM. For ***ER 96***, demand has fallen from ***ER 94*** between 5 percent and 10 percent through the year 2013. That results in a slightly larger surplus from ***ER 94*** over the 20 year ***ER 96*** planning period. All three DSM scenarios, show LADWP with enough committed plus uncommitted DSM resources to satisfy demand through the year 2011 when LADWP should experience a deficit between approximately 35 and 160 MW, depending upon DSM scenario.

Imperial Irrigation District’s generation mix consists of purchased power, coal, nuclear, oil/gas steam, combustion turbine and combined cycle units. Existing demand side management programs supply less than 1 MW in reducing peak demand. Annual peak demand is forecasted at 651 MW in 1996 growing to 1058 MW by 2015. Annual energy is forecasted at 2764 GWhr for 1996 growing to 4497 GWhr in 2015. Average growth in peak load is 2.6 percent per year, 1996-2015. Including meeting a planning reserve margin of 15 percent, IID resource deficit begins in 1996 at -9 MW and grows to -580 MW by 2015.

IID’s resource plan included evaluating seven different scenarios to meet future demand growth. The first scenario met growth through purchases only. Scenarios 2 and 3 included purchases and a repower. Scenarios 4-7 included purchases and cogeneration projects. The first three options have the lowest total cost on a present value basis. Only one of the cogeneration projects offers sufficient benefits to warrant further study by IID.

IID has indicated in their Resource Report that their goal is to “meet reserve margin criteria at the lowest cost to the ratepayer.” In keeping with that ideal, IID wishes to remain flexible with their options for meeting their needs in the future, especially with the uncertainties related to electric industry restructuring. IID has no immediate plans for building any plants in the next three years, and indeed appears to be avoiding any large capital outlays that may become stranded investments in the near future. However, IID has demolished a boiler at the El Centro Unit 1 in preparation for potentially repowering Unit 1.

Table 15
IID Supply and Demand Balance

IID hired consultants to do a rate study. Initial results indicate the rates charged the various classes do not adequately reflect the actual cost of service. As a result, IID's plans include lowering their commercial/industrial rates, an incentive to their customers, which may avoid future cannibalism by load aggregators. At the same time, the subsidized residential customers' rates will remain the same. This process may avoid the potential for redirecting the cost of debt service and capacity charges for purchased power to remaining customers (should customers leave IID's service for a load aggregator).

Since ***ER 94***, IID has canceled their Southern Arizona Transmission Project (as a result of the FERC Open Access NOPR that should lead to elimination of strategic benefits of transmission ownership and advanced supply opportunities), canceled an upgrade on their L line, and is in the process of installing a 2.5 mile 230 kV transmission line from their KS line to the Ave. 42 substation. IID has revised their emission factors (in response to filing their Title V Operating Permit later this year and in accordance with the 1990 Clean Air Act Amendments). IID expects to recapture 24 MW from Arizona Public Service in June of 1997 and the El Paso Electric purchase contract expires in May of 2002 (which should lower the average system rate by 1¢ / kWhr). IID has also contracted for a Demand Side Management study, to be completed in August, that will include technical, economic and customer data.

NEED FOR GOVERNMENT ACTION TO ENSURE ADEQUATE SUPPLIES

Whether or not supplies will be adequate to meet demand depends on the existence of incentives to encourage industry participants to take actions that lead to results that meet the government's definition of adequacy. The Energy Commission has only limited jurisdiction to implement incentives. The Commission is charged with evaluating trends in the electricity industry and advising governmental entities with jurisdiction over activities of industry participants what actions might be encouraged through incentives they have the jurisdiction to implement. The Commission could also use its jurisdiction over the certification of thermal power plants greater than 50 megawatts to encourage preferred actions. However, this method may be less effective than relying on more direct incentives implemented by other governmental agencies.

The Energy Commission's view of adequacy has historically been a multi-attribute one. Adequacy can be interpreted to mean that type, mix, kind, or cost of supplies that will maintain specific levels of system reliability, maintain statewide and service area growth and development, maintain a sound economy, preserve environmental quality, protect public health and safety, conserve energy resources, provide increased customer choice, protect electricity ratepayers, etc. Some specific actions could lead to improvements with respect to some attributes but worsening with respect to others. Therefore, a balancing of these attributes has historically characterized the Energy Commission's view of the adequacy of supplies and hence, the development of incentives for specific actions.

Staff filed testimony discussing the attribute of maintaining system reliability in a restructured electricity industry.[5] The National Electricty Reliability Council (NERC) and the Western Systems Coordinating Council (WSCC) establish operating criteria to maintain system reliability. Control area operators, including the Independent System Operator (ISO), have the obligation to meet these standards. Government entities with jurisdiction over control area operators, such as the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC), should not impose constraints on the ability of control area operators to effectively meet the NERC and WSCC operating criteria.

Many governmental entities are participating in the design of the new market and new regulatory mechanisms that will comprise the restructured industry. Energy Commission staff are among those government entities who have participated in working groups or regulatory proceedings established to design these new mechanisms. Staff recommends a continued involvement in these efforts for the purposes of fostering the attributes of maintaining growth and development and a sound economy, protecting electricity ratepayers, and providing increased customer choices. The governmental entities with the jurisdiction to implement incentives for actions within the new industry structure, the CPUC, FERC and the Legislature, should consider these attributes in their proceedings.

Many governmental entities are also participating in the efforts to include in the restructured industry incentives for actions which would preserve environmental quality, conserve energy resources, and internalize externalities and public goods issues into decision making. Energy Commission staff are among those government entities who have participated in working groups, regulatory proceedings, and legislative efforts established to design these new mechanisms. Staff recommends a continued involvement in these efforts for the purpose ensuring these attributes are considered. The governmental entities with the jurisdiction to implement incentives for actions within the new industry structure, the CPUC, FERC, the Legislature, the Air Resources Board (ARB), and local air quality management district boards should consider these attributes in their proceedings.

Because there is adequate involvement of governmental entities in all facets of the electricity industry restructuring, and because there exists considerable uncertainty as to the outcome of the many parallel decision making processes, staff recommends that the Energy Commission not impose a need test on proposed power projects under its jurisdiction during the pendency of ***ER 96***, other than to limit the aggregate amount of new power plant capacity certified to an amount of megawatts consistent with its integrated assessment of need.

ENDNOTES

1. Tables 4 and 5 of this testimony reproduce Tables 8 and 7, respectively, of the Commission's March 29, 1996, electricity forecast adoption order .

2. See Pacific Gas and Electric Company's ***ER 96*** Resource Report, Docket No. 95-ER-96, p.1.

3. California Energy Markets, May 24, 1996, p. 16.

4. Los Angeles Department of Water and Power Comments on the Effects of Industry Restructuring on Municipal Utilities; June 19, 1996; Docket No. 95-ER-96.

5. Likely Impact of Restructuring on System Reliability, Steve Baker, Roger L. Johnson, Jim McCluskey, Al McCuen, California Energy Commission Staff, June 5, 1996.